THE COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

Order Opening Investigation Into Distributed Generation
D.T.E. 02-38

INITIAL COMMENTS

OF THE

NORTHEAST ENERGY AND COMMERCE ASSOCIATION[1]

August 1, 2002

[1] These Comments do not represent the position of any individual corporate member of the NECA Board of Directors. Each of the NECA Board members retains the right to file its own comments, which comments would represent a more accurate statement of that company's position on the issues discussed herein.

I. Introduction

A. Northeast Energy and Commerce Association

These comments are submitted by the Northeast Energy and Commerce Association[2]. The Northeast Energy and Commerce Association (NECA) is New England's oldest and most broadly-based, non-profit trade association serving the competitive electric power industry. Founded in 1985, NECA's mission is to facilitate an open forum among all electric power stakeholders to foster the development and maturation of competitive power markets. NECA promotes environmentally sound, reliable and cost-effective wholesale and retail markets for the production and delivery of electric power supply, as well as competing energy services and resource alternatives, including conservation, innovative demand-side and power delivery technologies, renewable energy and distributed generation.

NECA's 300 members include developers and owner/operators of competitive power projects, both regulated and merchant transmission and distribution companies, power marketers and traders, fuel and equipment suppliers, power consumers and various service providers to the power industry, including law firms, investment bankers, environmental engineering and economic consulting firms.

B. What is Distributed Generation?

Distributed generation (DG) consists of power plants that are sited close to sources of electrical demand and meet specific requirements of the particular electrical demand. The distinguishing feature of DG is the connection to the grid at distribution voltage rather than at transmission voltage.[3]

Distributed generation can serve as a merchant plant for sale into the electric market or could serve a portion of a specific customer’s load requirements. Ideally, freestanding DG plants would be located strategically either to reduce existing loads, or to export power to constrained portions of the grid. DG plants could provide grid support, and could be ideal candidates for brown-field or re-developed sites using natural gas as the primary fuel. Small projects based on renewable resources also qualify, such as landfill gas, biomass and wind, if these resources are connected to the grid at the distribution or sub-transmission level.

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[2] NECA wishes to acknowledge the work of its New Markets Committee, which is co-chaired by Mark C. Kalpin, Esq., Hale and Dorr, LLP, and Roger D. Feldman, Esq., Bingham McCutchen, LLP, and whose White Paper served as the working draft for these Comments.

[3] The connection of DG at distribution level can limit the maximum size of the unit, due to voltage variation limitations, reactive load supply requirements, and existing base load on the feeder. For example, a typical DG installation on a 15 kV distribution line would be limited to the 2 to 5 MW size.

Other DG resources could be located at an end-user site. Some of these facilities are capable of supplying a significant part of an end-user's electric and/or thermal energy needs. Cogeneration plants supply combined heat and power and use all the thermal plant output, and are known for their highly efficient use of total energy. The DG plant may export power to the grid (and operate in parallel with the grid), or may only reduce or eliminate power supplied by the grid to the host facility during periods of high prices or outages. Most often, DG at customer facilities will be fueled by natural gas, using turbines, reciprocating engines or fuel cells, possibly with diesel fuel back up.

C. Why is Distributed Generation Important?

Distributed generation could be a benefit to all consumers. DG can be important during system peak demand periods. During these periods, the grid may be constrained, grid reliability may be at risk, prices could be high and generating resources could be limited. DG can provide added supply during these critical periods, by generating power to sell to the grid, and by supplying electricity to end-user facilities. Not all DG will be able to switch on during peaks; for example, some CHP (combined heat and power) plants may be limited in their ability to generate additional power during a peak, with demand reduction at the host facility as a more effective response during power shortages.

The end-user with DG at their facility can take advantage of differential pricing between the cost to generate from their own resources and the price of electricity available from the grid. When grid-supplied power is high relative to the onsite generator's fuel cost, end-users can save money by generating onsite; whereas when fuel prices are too high to make onsite generation economic, the end-user can buy power from the grid.[4]

There are five main benefits of DG:

1. Market pressure on regional prices may ease as new, load-centric resources are added and/or demand for grid power drops off at the ISO level.

2. Distributed generation resources could add to grid reliability, enabling the grid to operate more efficiently with less overloading of lines.

3. Newer, cleaner resources are brought online that avoid the more traditional source of emergency generation, diesel generation. This response is a function of the amount and location of non-dispatchable generation.

4. DG installations capable of supplying peaking power may lessen market power during periods when market power is most likely to be exercised –

[4] However, this ability to respond to prices must account for dispatch constraints imposed at the distribution level.

when supply is tight and demand is high. When the marginal price is based on numerous competing DG resources, the opportunity for market gaming by any one participant is reduced.

5. DG may have the ability to add more flexibility in newly required transmission design and may be environmentally and/or aesthetically preferable in many situations. Urban areas are becoming more difficult to serve with less costly overhead transmission.

D. The Challenges to Distributed Generation

These comments will focus on two of the areas of inquiry noted by the Department in its Order Opening Investigation: interconnection standards and standby rates, as well as two additional issues that NECA believes are appropriate for DTE consideration: grid dispatch and the DG environmental permitting process[5]. These challenges to DG stem from the combination of historical economies of scale associated with central station generation and related rate of return regulation.

II. Interconnection Standards

In general, utility engineering practice has been to serve new loads via a radial system, where the power flows by way of a single path from the substation to the loads. This design, which is sized by the load-balancing requirement of effective and efficient utility operations, has proven to be well suited for economical delivery to end-use customers. Design has been focused upon meeting the peak demand of the customers' loads. Each utility has a somewhat unique set of customer service concerns - including fault protection, local system stability, and power quality - with DG installations, based upon their system designs.

The unique nature of electrical delivery systems slows the development of common standards for interconnection of DG to the electric grid. However, in order to capture the benefits of a deregulated generation market, it is important to work towards common standards for interconnection. The following objectives are sought:

1. Interconnection of DG units should move towards performance standards rather than equipment specification.[6]

[5] While environmental issues are not directly jurisdictional to the DTE and, hence, were not specified in the Department's Order Opening Investigation, in response to Question No. 4 of the OOI, NECA believes that these additional major barriers facing the DG industry are "appropriate for consideration" and may assist the Department in its deliberations.

[6] Standards would be based on independent tests by recognized entities, which would ensure that no additional liability would be created on the part of any parties, including the utility, and potential damage risks to adjacent customers would not be increased.

2. A single, state-wide standard for interconnection would be preferable to individual utility service area standards, and a regional standard (*e.g.*, ISO-NE or Northeast RTO) would be better still. Unique utility system conditions within the purview of the standard could be addressed with addenda.

3. The T&D wires utility currently has an interest in whether a customer chooses onsite power. This interest can be negative due to potential reduced revenues, or positive due to the need for capacity relief on constrained facilities. The regulatory commissions should ensure that this interest is focused on the operation of the grid (rather than energy supply) so that the T&D utility can work as a partner, not a competitor, in the supply of DG solutions. The regulatory agency should evaluate this interest to incent the utility to provide new products and technology which would enable the utility to facilitate interconnections that provide the following:

    a. Minimum interconnection, protection, and insurance requirements, which then would need modifications, based on the particulars of the installation. Due to the sheer number of variations on the system (*i.e.*, existing loading, voltage stability, VAR requirements, radial versus network, etc.), there is no one-size-fits-all. The existing distribution system is comprised of thousands of distribution circuits (with at least five different distribution voltages – 4.16, 13.2, 13.8, 23, and 34.5 kV) in NE, each with unique characteristics.

    b. Rate recovery for the costs of the additional intelligence and controls needed for proper dispatching to occur (SCADA).

    c. “One stop” negotiation and the ability to mediate technical issues and liability concerns.

4. There should be a common basis for determining the value of net-metered energy. Net metering for kW loads above a minimum threshold level should be based on the market price for energy, by season and time of day, at the distribution delivery level.

5. The need for real-time metering will be critical to tie into the distribution company’s SCADA system, as well as properly credit or charge the DG customer as necessary under subparagraph (4) above. This information also will be required by the ISO to properly account for export onto the system. Advanced metering of this sort also will help to document operation of the DG system in the event of a related dispute.

III. Standby Rates

One of the more significant issues facing a customer that is considering the installation of DG relates to the cost of obtaining back-up or standby power (herein collectively referred to as "standby power") at times when the DG experiences a full or partial outage. These outages can occur for a variety of reasons, ranging from planned maintenance outages to unplanned forced outages to changes in the weather, if the DG happens to derive its "fuel" from the sun or the wind. While one source for this power can be a customer-owned back-up supply, it is frequently more economic and more reliable to obtain this standby power from the grid. As a result, the non-commodity charges from the incumbent electric distribution utility can often have a significant effect on the total costs of a DG installation. Obviously, the greater the ability to avoid these fixed, or demand-based, standby charges, the less costly the DG installation will be to the customer.

At present, there are many ways that standby services are priced by the distribution companies. The pricing may be based solely on the historic embedded cost of service, it may reflect the marginal cost of service or it may be the result of a blend of these approaches. Often, the cost-of-service studies that were used to structure the previously integrated utility's retail tariffs have not been updated to reflect the restructuring of the industry, let alone the now emerging potential for load-centric DG.

NECA submits that the starting point for economic pricing of standby services provided by distribution utilities to DG should be the long-term, marginal cost of service. With respect to the commodity portion of the DG customer's standby service, this service is currently open to competitive suppliers in Massachusetts and, hence, the market is performing the function of providing marginal cost signals. This approach allows the DG customer to shop for standby supply through bilateral arrangements or the distributed generator can obtain supply from the distribution utility under its existing tariffs.

With respect to the pricing of the non-commodity components of distribution company-provided standby service, the same long-term, marginal cost principles should govern. However, in this case the wires company is acting in a regulated monopoly role and the DTE is charged with ensuring that the rates reflect true marginal costs. In certain situations, for example, a DG application may be sited in a location where its marginal cost impacts are simply *de minimis*, due to line and transformer capacities in excess of the DG's maximum possible standby load. In other cases, the maximum standby load of even larger DG installations may simply require no additional distribution system investments. These examples would suggest that a location-based marginal distribution cost method of DG pricing might be considered, if administratively feasible. More specific suggestions that may facilitate DG in this context include:

1) Certainly, the distribution companies can offer choice to their customers in a regulated context as well. Distribution capacity could be reserved on a full load, partial load or no load basis along with options for automatic load backup, manual backup or scheduled backup services.

2) Pricing for each of these services should differ due to the marginal economics of each offering. For example, an automatic backup of full load would command the highest price whereas a scheduled backup service would be priced lower to reflect the economic benefits to the distribution company from being able to schedule use of capacity.

3) Each of these offerings should have their commodity and non-commodity components disaggregated to facilitate comparison to the alternate of onsite and third party back-up for selecting the best option based on operational costs and benefits.

One of the more contentious issues in this regard is the degree to which the distribution companies should be permitted to assume certain frequency and peak coincidence factors of DG outages. This issue is made all the more problematic due to the fact that DG is in its early stages of development and deployment and there is a less than an ideal amount of experiential data.

At one extreme, some utilities would argue that its full cost of service must recovered from the DG customer each and every month on the assumption that there may be an on-peak outage and that the distribution system must be built and maintained to accommodate the customer's maximum load in such an event. At the other extreme, some DG advocates would like the utility to provide such firm peak service on an entirely volumetric, i.e., paying only in those instances and to the extent that its outage coincides with system peak. If an individual DG customer, they suggest, requires delivery at a time of off-peak demand, then it is arguable that the DG outage has caused the utility to incur very little, and perhaps no, additional cost.

NECA[7] recommends that the Department investigate the feasibility of a possible compromise that could take into account the probability of a DG application's outage coinciding with the distribution company's system peak. In theory, each class of DG technology and fuel resource might have its standby rates reflect the probability of its own unique performance coinciding with the distribution utility's system peak. While DG as an emerging load-centric market may be in its infancy, there may be a good amount of performance data available regarding many of the technologies that are expected to be used in DG. For example, if a particular engine and fuel DG application has been proven to have a 10% outage rate, the utility would only be permitted to charge 10% of the fixed costs

[7] A minority of NECA Board members has expressed a concern that the probabilistic approach to the non-commodity portion of standby rates, as discussed in the text, may be administratively infeasible and potentially discriminatory against non-DG Customers.

associated with standing ready to serve that DG customer in the event of an on-peak outage. Over time, with greater numbers of DG installations, DG performance should move to the historic mean, avoiding potential subsidies by non-DG customers.

Such an approach would also be of great value to the leading renewable technologies, wind and solar, which are intermittent in nature. The probability that a wind turbine will be producing power at its maximum capacity is higher at times of winter peak, while a solar PV installation has a higher probability of coinciding with summer peak. If a methodology is derived that reflects these differences, the distribution company's peak coincidence-driven standby fixed cost charges will more closely reflect the true marginal cost of service. Such a policy would also have the added benefit of supporting the Commonwealth's official policy of encouraging renewable energy facility development.[8]

Finally, the robustness of such a probabilistic approach to standby rates would be enhanced if each DG customer's peak coincidence factor was required to be adjusted over time to account for both the unique operating characteristics of that customer's performance[9], as well the benefits associated with aggregating entire classes of DG technologies, as discussed above.

IV. Additional Issues Appropriate for Consideration

A. Grid Dispatch

End users realize the benefits of DG when they are able to respond to wholesale market signals - usually triggered by high prices or capacity constraints. This ability to respond is enabled when DG (and their host customers) can participate in the wholesale market by dispatching power to the grid, reducing load through peak shaving or by taking other demand side responses.

The kinds of regulatory actions needed include the following:

1. Provide demand side bidding in the wholesale market, adjusted for location, that allows DG (and their host loads) to bid willingness to reduce load into the grid, comparable to central station units.

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[8] A similar desire to ease the barriers to entry into the new power markets for intermittent renewable energy resources, in part, formed the basis of the recent FERC-approved tariff amendments implemented by the California ISO to enable these intermittent technologies to schedule energy into the hour-ahead market. (See Re: California ISO; Docket No. ER02-922-000; 98 FERC 61, 327 (March 27, 2002).

[9] One concern expressed by a minority of the NECA Board relates to the fact that the performance of some DG customers will also be influenced by such drivers of economic self-interest as market clearing prices, i.e., not solely by historical technology reliability. This concern may be ameliorated to the extent that the peak coincidence factors were partially adjusted each month to account for actual demand placed on the system for that month, just as certain Massachusetts utilities currently account for a customer's monthly demand.

2. Provide demand sale-back, adjusted for location, that allows DG resources (and host loads) to release power take-off from the grid for sale back to others.

3. Allow the bidding of aggregated DG resources (located within the same load pocket) in order to qualify as a power block for grid dispatch.

4. Reform of the use of load profiling by the ISO for the purpose of assigning load responsibility. The DTE should encourage end use customers to respond to peak demands and wholesale market prices based on actual metered data.

5. The DTE should ensure that retail suppliers give customers an option to choose time of day rates and hourly metered rates which reflect wholesale real time prices to the extent practical.

B. Environmental Issues[10]

In general, DG resources should be located near load centers. However, customers typically make their DG siting decisions based on economic considerations. These sites are likely to be in areas that are non-attainment for ozone standards and will often be sources of local concern about air emissions. Large-scale DG projects, or DG additions to an existing major facility, may require the same Lowest Achievable Emission Reduction (LAER) technology for oxides of nitrogen as a full scale power plant under federal Clean Air Act permitting requirements. Smaller scale DG projects, however, trigger only state permitting requirements which vary from state to state. In Massachusetts, for example, even the smallest DG resources must meet Best Available Control Technology (BACT) standards consistent with economic practicality. The environmental permitting process, however, has been almost entirely geared to central station generation permitting and operation. The state BACT review process itself has been administered on a case-by-case basis in a way that imposes a level of development risk that may be hindering wide scale application of DG.

Implementation of the following actions would reduce barriers to DG, while accelerating the retirement of more polluting resources:

- Presumptive BACT requirements for NOx and CO for fossil fuel-fired DG resources and differentiation of these requirements by equipment size,

[10] NECA is cognizant of the jurisdictional limits of the DTE in the area of environmental permitting. However, NECA believes that for the Department's views on the "importance of distributed generation as a resource option in the restructured electric industry" to be fully realized, it will not be sufficient to address only the issues specifically identified in the Department's Order Opening Investigation. Therefore, NECA specifically calls on the DTE to engage in inter-agency collaboration and, if necessary, to support legislative efforts to investigate ways in which the environmental permitting requirements in Massachusetts can be optimized for DG in an environmentally responsible manner, consistent with the recommendations suggested herein.

technology (engines, boilers and turbines) and fuel (natural gas and very low sulfur transportation diesel).[11]

- A general permit for emissions from facilities that meet certain requirements (*e.g.*, maximum production limit for criteria pollutants, use of fuel cells).[12]

- A bright line air dispersion modeling requirement based on project size and location factors.

- Streamline and standardize permitting process for DG facilities below a specified size threshold.

The DG permitting process should be quicker, and the outcome relatively certain. Standardization in air permitting could also bring economies of production and configuration by equipment manufacturers eager to meet this emerging market need, as well as provide economic incentives for manufacturers to develop and package cleaner DG alternatives.

Thank you for your consideration of these Comments.

Respectfully submitted,

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[11] The NECA Environmental Committee has prepared proposed presumptive BACT requirements for DG Projects in Massachusetts which would substantially streamline permitting. NECA is willing to provide upon request of the Department or any party.

[12] The State of Connecticut's Department of Environmental Protection on May 1, 2002, promulgated a General Permit approach for the construction and/or operation of new or existing DG (DEP-AIR-GP-305).